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Implications of Reduced Fault Level and its Relationship to System Strength: A Scotland Case Study

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SUMMARY

The integration of Inverter Based Resources (IBRs), which displace traditional Synchronous Generators (SGs), presents new challenges to power system operation. SGs naturally provide voltage source behaviour, allowing them to be represented by a voltage source behind an equivalent impedance. In contrast with SGs, IBRs' behaviour during faults is typically like a controlled current source, and their responses to network faults are driven by their control strategies and the current limited capacity of the converter, resulting in a reduced fault current infeed during network faults.

As a fault level can be seen as a measure of the equivalent system impedance, based on the 50 Hz Thevenin equivalent, it has also been used as a measure of "system strength", e.g. through the use of various Short Circuit Ratio (SCR) metrics. As a result, the terms "fault level" and "system strength" are sometimes used interchangeably, which may be largely valid for SG dominated systems. However, the fault level metric does not always capture all aspects of system behaviour in the context of high IBR penetration. Hence, particularly in systems which have a high number of IBRs relative to SGs, this paper argues that there is a need to make a clearer distinction between the low fault level issues and other challenges. The fault level remains a useful metric in the context of power system protection and to assess system characteristics during faults, such as the voltage depression. Meanwhile, other system challenges include a high voltage sensitivity during quasi-steady state system conditions, such as IBR control interactions.

This paper has assessed fault levels in the Scottish transmission area of the Great Britain (GB) power system, an area which has a high number of IBRs and very few large SGs, some of which are close to retirement. These factors have motivated the system operator (SO) to launch a tender exercise – the Stability Pathfinder (SPf) Phase 2 – that is seeking new sources of fault current to connect to the system. Although the SPf has been motivated by closure of SGs, it is shown in this paper that, at many locations, equipment outages can reduce local fault levels more than the status of the available large SG units, and that fault level contributions from SGs are relatively localised. In addition, a sub-synchronous oscillation event in August 2021 suggests that challenges related to a high voltage sensitivity also exist in Scotland. Moreover, the fault levels during the event were not unusually low. Hence, considering the limitations of fault level as a metric for quasi-steady state voltage sensitivity challenges and that the observed fault levels can already be low and are not very sensitive to the anticipated closure of SGs, it is concluded that procurement of fault level alone may not be adequate to address some of the operational issues in the Scottish transmission system with further integration of IBRs. More work should be done on defining the exact metrics for quantifying the system needs in order to ensure security of supply in the most cost-effective manner.

KEYWORDS

Fault Level, System Strength, Voltage Sensitivity, Power System Faults, Power System Stability.

1 INTRODUCTION

In GB, like many other countries, the transition away from fossil-fuelled SGs towards low carbon IBRs is well underway. It is now common to see IBRs displacing SGs in system operation due to their low short-run marginal cost and a priority to utilise low carbon generation. However, the reduction in the number of online SGs and the concurrent increased penetration of IBRs presents challenges to ensuring system security at both a regional and system-wide level [1].

Traditionally, the quantification of fault level has primarily been used in switchgear rating and the design of protection systems. However, the fault level has also been used as a measure to describe the "system strength" at a particular point in the network and these terms have sometimes been used interchangeably [2]. In recent years, the understanding of system strength has been evolving, and the term has been used to describe a broad set of operational challenges including, for example, the correct operation of protection systems or sub-synchronous control interactions of IBRs [3], [4]. As a way of addressing system operability challenges associated with a high penetration of IBRs, two SOs – AEMO in Australia and National Grid ESO (NGESO) in GB – are going some way towards defining minimum fault level requirements [2], [5]. Via the Stability Pathfinder (SPf) Phase 2 tender exercise, NGESO is seeking to procure fault level in the Scottish region of the GB transmission network. However, as the penetration of IBRs becomes more dominant in the system and new challenges emerge, the use of a fault level metric, while it remains related, can become less effective to assess some of the issues, e.g. interactions between IBRs, that are often classified under the term system strength. If the requirements of the system are not recognised explicitly and the needs quantified appropriately under a range of system operating conditions, there is a risk that uncoordinated and unnecessarily costly solutions will be adopted and innovative approaches overlooked. There is therefore a need to re-assess the use of fault level in the context of the current challenges related to the term system strength.

Section 2 of this paper reviews the meaning of fault level in the context of a high penetration of IBRs and its relationship to system strength. Then, prompted by the GB system operator's procurement of sources of fault current, section 3 describes the calculation of fault levels in Scotland under low SG dispatch conditions and during a sub-synchronous oscillation event that occurred in August 2021. We also consider the impact on fault levels of the closure of local SGs, equipment outages and the potential contribution from the SPf Phase 2 tender programme. Section 4 concludes the paper.

2 FAULT LEVEL AND ITS RELATIONSHIP TO SYSTEM STRENGTH

2.1 The concept of fault level

Fault level is a measure of the amount of current that would flow at a given location if there was a short-circuit fault at that location. It is dependent on the equivalent source impedance at the fault location and the response characteristics of nearby sources of fault currents. It can be used to characterise the contribution of short circuit current from a group of sources or from the entire system. Typically, it is quoted as the product of the RMS short circuit current at the point of fault and the pre-fault voltage. For an apparent power (MVA) fault level at a given point in the system, the equivalent system impedance in per unit form ($Z_{s\ (p.u.)}$), which is also equal to the Thevenin impedance of the system [6], is given by equation (1). Therefore, a high fault level at a given point in the network means a low equivalent system impedance.

$$Z_{s\ (p.u.)} = \frac{MVA_{base}}{MVA_{fault\ level}} \times \frac{V^2_{phase-phas\ (kV)}}{V^2_{base(kV)}} \quad (1)$$

When modelling the fault current contributions of synchronous and induction machines, these sources can be represented by a voltage source behind an equivalent impedance, based on the 50 Hz Thevenin equivalent. In short circuit calculation programs, static calculation methods are used with the application of various factors, and the time varying behaviours of synchronous generators during faults are represented by their sub-transient, transient, and synchronous reactance and by their sub-transient and transient open loop or short-circuit time constants [7].

In contrast with SGs, the fault response of an IBR is driven by the capacity of the converter, its control system and the control strategies in place to interface with the grid. In general terms, IBRs behave like a controlled current source, with the current limited during faults to protect the converter's components. It is often assumed that a low fault level resulting from the use of IBRs means a low system strength and that, in turn, means that voltages will be highly sensitive to changes in system operating conditions. However, this does not always follow. An example is in offshore AC networks that are fully driven by converters and could have a relatively low fault level but can achieve low voltage sensitivity due to the deployment of grid forming control. In addition, depending on the grid connection requirements, most IBRs will be required to activate fault ride through (FRT) control modes during a fault, and the controls are required to prioritise delivery of reactive current as a function of the post fault retained voltage to support the network [8]. Therefore, during a fault, the short-circuit contribution of IBRs should be modelled by a current vs. voltage relationship. However, due to the current limitation, this current vs. voltage relationship is non-linear. Therefore, they cannot be represented by the classical model of a voltage source behind an impedance at the fundamental frequency.

When considering transmission network voltage levels, it is typical to assume that the system reactance is much higher than the resistance i.e. it has a high X/R ratio. In SG dominated networks, the system impedance is largely defined by the synchronous generator stator inductance and equivalent inductance of the network. From a system fault level perspective, a higher X/R ratio results in a slower decay rate of the initial asymmetrical fault current resulting in higher sustained initial peak fault currents [6]. From a voltage stability perspective at a generator connection point, a low network X/R ratio indicates a higher voltage sensitivity to changes in active power (due to increased network voltage drops) [9].

2.2 The Concept of System Strength

The concept of system strength has been increasingly discussed in relation to the challenges associated with high penetration of IBRs. As these are often new and emerging issues, it has led to varied definitions of system strength being made, which can often differ in their scope. The over-arching theme of the definition of system strength is that it relates to the ability of the power system to maintain its core characteristics when the system becomes altered from its normal state. This implies a strong correlation with the concept of power system stability [1]. A strong system is more tolerant to perturbations, and it recovers easily from major disturbances [4]. The majority of definitions of system strength and analyses conducted relate it to both the sensitivity of voltages to changes in system conditions and to the fault level at that location [10]–[12]. However, some definitions also consider system inertia and the sensitivity of system frequency to changes in active power [3], [9]. It might be argued that the sensitivity of voltages to changes in system conditions and the fault level at the point of connection are related to each other in that they both depend on equivalent system impedance but including the system inertia in the definition of system strength and therefore implying that frequency sensitivity is included can confuse different issues which can adequately be considered separately.

2.2.1 System Strength Metrics

The Short Circuit Ratio (SCR) is the ratio of the fault level to the nominal active power of an infeed and has been a widely used index for assessment of the strength of the connection point for IBRs and to describe the kinds of system conditions that they may be required to operate under [13]. The lower the SCR, the weaker the system is said to be. The classic SCR is only appropriate when considering a single IBR, at a single point of connection, and does not account for the presence of other converters [12]. The Weighted SCR (WSCR) metric determines an aggregate SCR at a common “virtual” point of connection [9], [12]. A single WSCR value may represent multiple IBR which have varying amounts of interaction but does not consider the impedances between them. SCR with Interaction Factors methods (SCRIF) [9], [14], [15], aim to directly account for impedances between multiple IBRs and assess their interaction within an area of the power system. The approach is based on assessment of the observed voltage change at one bus for a small voltage change at another bus, i.e. the voltage sensitivity between IBRs, to give a better estimate of the grid strength. The Available Fault Level (AFL) method uses the principle of superposition to assess the impact of new IBR connections on locations in the AC network where IBRs are already connected. AFL is based on the premise that IBRs require a minimum fault level to operate in a stable manner and that the minimum SCR for existing and new connections is known.

2.2.2 Limitations of SCR metrics

The various SCR metrics outlined above have some limitations. The WSCR metric has been used by ERCOT (the SO in Texas) to set wind dispatch limits from the Panhandle region [14]. However, system strength assessments in the ERCOT system highlight that, as wind penetration increases and the connections are spread across broader areas, definition of the boundaries for using the WSCR metric becomes blurred, and it becomes less reliable when setting real-time operating limits [16]. The AFL method has been applied by AEMO (the SO in Australia) as a screening metric to determine the need for detailed studies using Electromagnetic Transient (EMT) simulations. However, in some areas with a high IBR penetration, the AFL can be considered too approximate and full EMT analysis is always required [17]. Regarding the SCRIF metrics, there is a lack of experience and/or published studies applying this metric in real world planning or operational practices.

Another limitation of the SCR metrics is one of consistency. Each SCR metric will suggest different system limits and will suggest sets of requirements to be imposed on network users. What appear to be the critical limits will be different for each converter manufacturer based on their variation in control strategies and parameters used [12]. In addition, inconsistency can be experienced when interpreting the fault level to be used in the calculation. Short-circuit currents change dynamically during the period of the fault with symmetrical and asymmetrical components. Therefore, a different fault apparent power can be chosen during the sub-transient or transient periods and include only the AC symmetrical RMS and sometimes the DC components [6].

The SCR metrics described in this section, and various extensions to them, are all based on the equivalent Thevenin impedance at the fundamental frequency. The impedances of converters vary across a wide frequency range which is influenced by its output filter, control strategy, control mode and the network operating conditions [18], [19]. Therefore, stability in an IBR dominated system exhibits multi-frequency dynamics and SCR metrics based on the fault level do not capture the true behaviour of IBRs [20]. Fault level based metrics may remain useful for early indicative screening of system strength challenges, but there is a necessity to move towards a multi-frequency response characteristic model and detailed EMT analysis to determine stability in converter dominated networks.

2.3 Relationship between Fault Level and System Strength – Classification of Issues

Many challenges are emerging which are often attributed to a 'low system strength' and are related to operating the system with an increasing penetration of IBRs [3], [10]. The challenges typically quoted span the topics of power system stability, power quality and protection systems [1], [4]. Furthermore, as discussed in sections 2.1 and 2.2, the established metrics for system strength that are based on the fault level may not properly represent the system's behaviour in the context of high IBR penetration. Often, the need to mitigate against this broad set of potential operational challenges is quantified via expressing a need for fault level. However, while it remains important and necessary to plan for potentially very low fault levels, not all actions to mitigate 'low system strength' challenges require an increase in fault level, suggesting that the single term 'system strength' can lead to ambiguity. There is, therefore, a need to make a clearer distinction between the low system strength and low fault level issues. These are discussed in the subsections below.

2.3.1 System strength and quasi-steady state voltage sensitivity

When electrically distant from a strong voltage source, changes in system conditions will lead to wider variation in voltage, i.e. there is a high voltage sensitivity. These changes in conditions include, for example, network switching and changes in load. Assuming the converter controls are properly tuned for the prevailing system conditions, IBRs are as able as similarly rated SGs to maintain voltages at near-nominal level during non-faulted conditions. However, they are less able to supply fault currents during a short circuit fault. Therefore, a distinction can be made between the issues associated with voltage sensitivity during non-fault conditions, and the issues during fault conditions and a low fault level [21]. A high voltage sensitivity can also be a concern in the period after fault recovery, i.e. when the system should have regained equilibrium and generation sources recovered their pre-fault active power.

One of the most prominent emerging challenges with respect to system operation is converter control interactions. IBR converter control loops typically have fast response times and can act over multiple timescales when regulating the current and power exchanged with the grid, which may lead to voltage and power oscillations across a wide frequency range [1], [4], [22]. Where the voltage sensitivity is high between IBRs, control interactions can be more prominent.

The most cost-effective mitigation of high voltage sensitivity may or may not require an increase in the fault level. For example, mitigating actions for converter control interactions can include the use of damping control methods implemented in the existing or new IBR devices on the network [23], [24]. In addition, implementing grid forming (GFM) converters over traditional grid following (GFL) converters can reduce voltage sensitivity and make the grid appear 'stiffer' due to their voltage-source behaviour [3] and can be investigated as a mitigating action [25], even though these solutions might not contribute additional fault level above their nominal current ratings.

2.3.2 Fault conditions and fault level

During faulted conditions that lead to a voltage depression outside of statutory limits, the system's state is dependent on the ability of sources within the network to supply fault current, and therefore the fault level metric remains highly applicable. The system's state is also dependent on the behaviour of IBRs during fault conditions, during which the IBRs implement different control modes to fulfil their FRT requirements.

A major impact of increasing penetration of IBRs and lower fault level is on the performance of protection systems, i.e. the ability of protection systems to detect, locate and clear faults in a timely manner. A high penetration of IBRs can lead to an increased risk of delayed or failed tripping of protection relays, resulting in faults remaining on the system for a longer duration [26]. The impact depends on the type of protection scheme. For example, conventional over-current protection schemes will sense the magnitude of fault current and therefore it is jeopardised by the lower fault current contribution from IBRs [19]. In addition, protection schemes such as directional overcurrent and distance protection often rely on sequence components to detect the fault direction and select the faulted phase. Standard IBR control implementations do not produce zero sequence and negative sequence components, i.e. they supply balanced fault current for unbalanced faults, which can jeopardise the correct operation of these schemes [27]. Therefore, the protection system performance challenges are not only related to fault level magnitude, but also the different characteristics of the supplied fault current from IBR and can sometimes be addressed by improving IBR controls [28].

A reduction of fault level results in an increased severity of a voltage depression during faults. This means that the effects of the fault can propagate further through the network. A consequence of this is that a lower retained voltage and fast voltage angle change can degrade the FRT performance of grid-following IBR due to its Phase Lock Loop (PLL) controls losing synchronism [29], [30].

Mitigating actions for low fault level issues can either involve increasing the fault level, which is the typical solution to date, or improving the resiliency of assets, such as protection systems or IBRs, to operate at a lower fault level. GFM converters are increasingly being discussed as a potential solution to low fault level issues as they can be less reliant on the PLL during fault conditions [31]. During a fault, depending on the control strategy used, the GFM converter may utilise a current control mode to limit the current and, like GFLs, are likely to still provide limited and balanced fault currents only in the positive sequence, unless Grid Codes are modified to specify otherwise. Therefore, the GFM might not mitigate a low fault level issue [32].

3 FAULT LEVELS IN THE SCOTTISH TRANSMISSION AREA

In response to an expected drop in fault levels in Scotland as a result of closure of large SGs, the system operator in GB, NGESO, has launched a tender exercise – Stability Pathfinder (SPf) Phase 2 – that is seeking new sources of fault current to connect to the system [5]. In order to gain a better understanding of the nature of the fault level challenge in Scotland and potential impact of the SPf, an independent assessment of fault levels has been conducted and is reported in this section.

3.1 Power System Model

A representative GB transmission system model, developed by the University of Strathclyde, is shown in the top left of Figure 1. The model represents the Scottish region in greater detail than the rest of GB which is shown by the blue and green areas that are enlarged in Figure 1. Each area is owned by a different Transmission Owner (TO). The model includes 53 transmission nodes at 132 kV, 275 kV and 400 kV, 28 of which are in Scotland. Loads are modelled at 11 kV with associated supply transformers. Generator transformers are also included. All large transmission connected generation in GB is modelled [33], and IBR and hydro generators with a smaller rating are aggregated at the nearest available busbar. The contribution to fault levels from distributed generation or from embedded HVDC links has not been modelled. Wind generators are assumed to contribute 1 pu fault level in the sub-transient and transient period of the fault.

The model has been validated against the available fault level data published in the Electricity Ten Year Statement 2020 (ETYS) by NGESO [34]. In this model, the network has been simplified by aggregating system elements, e.g. the impedance of multiple transmission lines, and assumptions are made for data that are not available, e.g. generator internal impedances. This aggregation and use of assumptions allow a reasonable representation to be made of the areas being modelled. However, there will always be some differences expected when comparing to a full system model. All of the fault levels shown in this section are calculated based on the G74 calculation procedure [7] and fault currents are calculated according to the SPf tender programme definition [35].

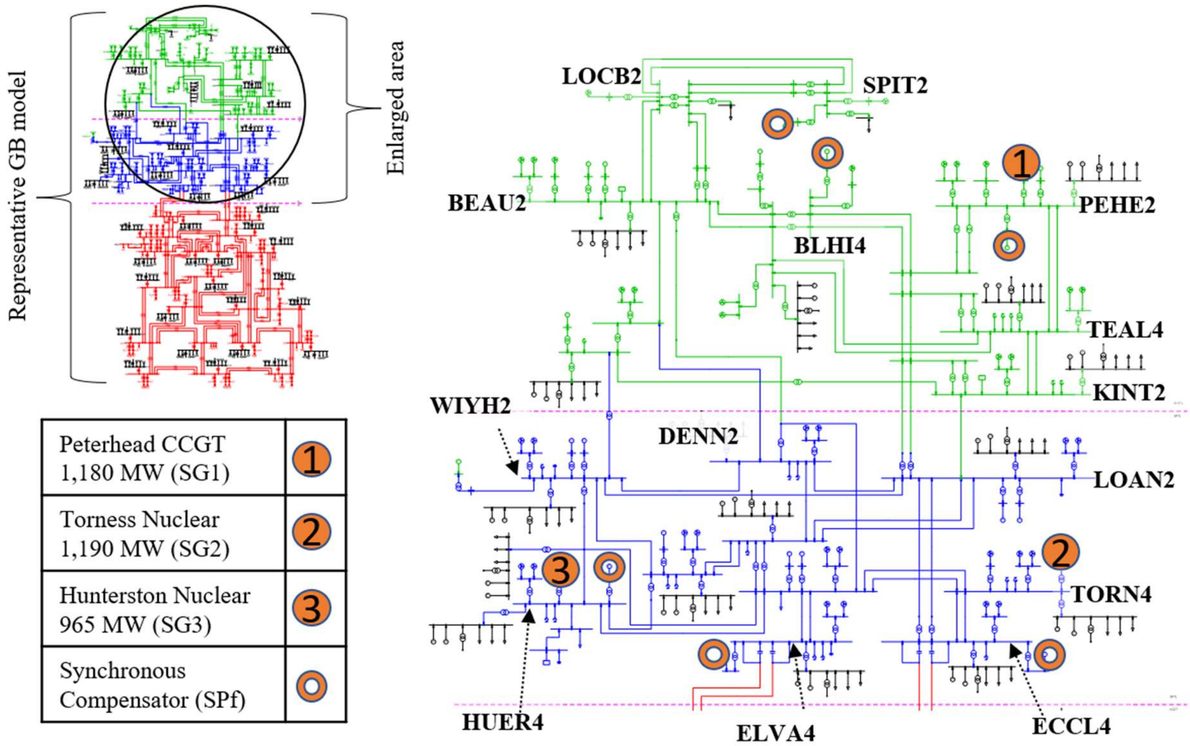

Figure 1: Representative GB power system model - including enlarged Scottish area showing location of main SGs and assumed locations of synchronous compensation from the NG ESO SPf Phase 2 tender

3.2 Case studies

Various generation dispatch conditions have been modelled to assess periods which exhibit low fault levels in the Scottish transmission area. These conditions included low demand, variation of IBR penetration and variation in the outputs of the key SGs in Scotland, i.e. Peterhead (SG1), Hunterston (SG2) and Torness (SG3) (see Figure 1). A case study of the 4th of April 2021, during the half-hour period ending 23:30, has been selected as a representative base case with low fault levels in Scotland. (See Table I).

On the 24th of August 2021 at around 04:50, a sub-synchronous oscillation (SSO) event was observed in the Scottish transmission network. During this event, voltages on the 400 kV network oscillated between approximately 355 kV and 435 kV at a frequency of 8 Hz. Two similar oscillations occurred which were 30 minutes apart and each lasted for around 20-25 seconds, during which some users tripped off the system [36]. At the time of writing, no detailed analysis of the event has been published by the SO. However, to provide an indication as to whether low fault levels at the time could have been a potential indicator for adverse system conditions leading to the SSO, it is included here as a second case study. (See Table I).

Table I: Modelled GB system conditions for the 4th of April 2021 (base case) and 24th of August 2021 (SSO case)

	04/04/21 (base case)			24/08/21 (SSO case)		
Area	North Scotland	South Scotland	Total GB	North Scotland	South Scotland	Total GB
Total SG output (MW)	298	342	9,754	15	2,261	14,545
Operating status of main SG units (fig. 1)	SG1: off	SG2: 1 unit SG3: off	-	SG1: off	SG2: 2 units SG3: 2 units	-
IBR output (MW)	937	1,733	9,858	6	0	2,067
Total generation (MW)	1,236	2,076	19,614	21	2,261	16,627
Total demand (MW)	583	1,597	19,221	422	1,262	16,328

3.3 Fault levels during the SSO Event

During the period when the SSO event occurred, there was a very low amount of active power generation in the north of Scotland region, which is the area reported to have the highest oscillations. There were some hydro units and some wind farms online that were operating at a very low active power dispatch. Compared to the 4th of April base case (orange bar in Figure 2), the August 24th case (dark blue bar in Figure 2) shows no noticeable reduction in fault levels. In the South of Scotland area, both Hunterston and Torness nuclear plants (each has 2 reactors) were running close to full output and provide high fault levels across the southern part of the region (WIYH2 to TORN4 in Figure 2), considerably higher than the base case where only one unit at Torness was online. With no SSO having occurred on April 4th, from Figure 2, it could be concluded that a minimum fault level threshold would not have been a useful indicator for the SSO event.

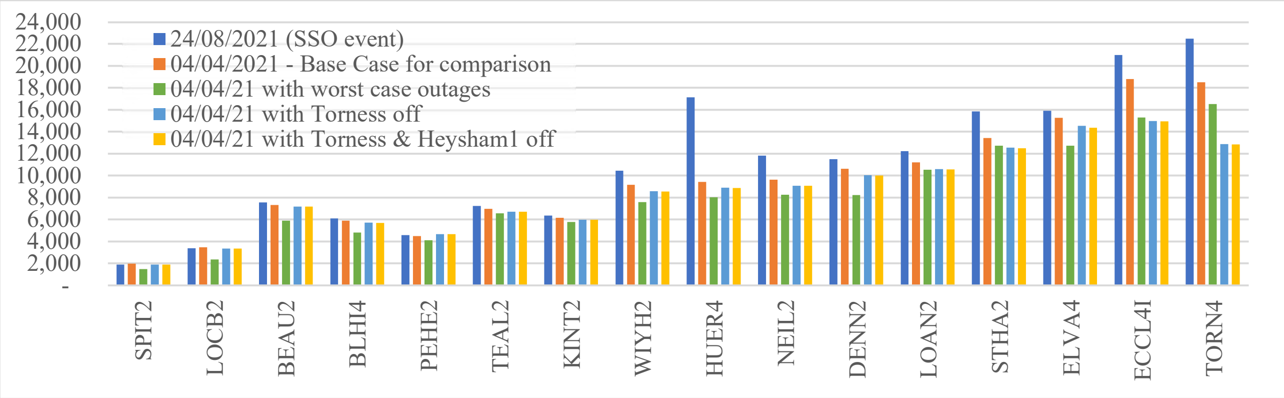

Figure 2: Fault levels for base-case, SSO case, and the effects of equipment outages and SGs being offline

3.4 Effect of large synchronous generation being offline and equipment outages

Taking power system elements out of service, such as lines and transformers, changes the equivalent impedance of the network as seen at a given location and can reduce the amount of fault infeed in the locality of the outage. Multiple cases with single outages have been tested. Figure 2 shows the fault levels at each node for the intact system (4th April 2021 base case, orange bars) and the worst-case post-outage fault level (green bars). The worst-case post-outage fault level is the result of the outage which causes the greatest reduction in fault level at that node. Applying outages of key system elements can lead to a considerable reduction in local fault levels. In some cases, the outages tested can reduce the fault levels more than a change in the status of the available large synchronous generating units does. If low fault levels are a genuine problem in Scotland, outage planning in Scotland may become increasingly challenging, and may present a major issue for facilitation of new low carbon generation as it often requires long construction outages.

Many of the large SGs in or close to Scotland are approaching the end of their life and are expected to be decommissioned in the next few years. Specifically, the estimated decommissioning date of Hunterston is January 2022, Heysham 1 and Hartlepool are in March 2024, and Heysham 2 and Torness are currently scheduled for 2030 [37]. Figure 2 also shows the effects on the fault level from the base case of taking Torness offline (blue bars) and then additionally Heysham 1 offline (yellow bars). With Torness offline, the fault level is clearly reduced in the local vicinity (nodes TORN4 and ECCL4). However, this case shows that taking Torness offline, and therefore leaving none of the three large SGs active in Scotland, does not materially reduce the fault levels across the rest of the Scottish system, compared with the 4th April 2021 base case. In addition, running without the Heysham 1 generator in the North of England has little influence on the fault levels in Scotland due to the electrical distance between these generators and the transmission nodes being studied. These cases show that, in some locations, the closure of the main synchronous generating plant in Scotland may not reduce the three-phase fault levels much below those that are already being experienced during credible system conditions.

3.5 Effects of NG ESO Stability Pathfinder Phase 2

Phase 2 of the SPf, which was launched in June 2020 and has an earliest possible start date of September 2022, is focused on procuring fault level in Scotland. NGESO has specified a need for fault level at eight specific locations in Scotland. Seven of these nodes modelled here and are shown in Figure 3 where the dashed black line is the fault level requirements defined in the SPf tender [5]. One possible solution made up of six synchronous compensators (SCs) with a total rating of 860 MVA would meet the SPf fault level requirement. The SCs have been located directly at the areas of need defined in the SPf tender and can be seen in Figure 1.

The individual apparent power ratings of the SCs and their respective fault level contributions are shown in Figure 3. The requirement at LOAN2 is met without a SC installed. The effect of this solution to SPf phase 2 on other locations is shown in Figure 4. The solid blue bars show the worst-case generation dispatch and solid green bars show the worst-case outages from Figure 2. The striped bars of corresponding colour show the effect of the addition of the SCs on each of the study cases. Under a worst-case generation dispatch, an increase in fault level can be seen throughout the network and generally brings the fault levels above those currently being experienced. Under a condition of a worst-case outage, the addition of the SCs raises the fault level close to the base case. However, it can also be seen from Figure 4 that the lowest fault levels remain low.

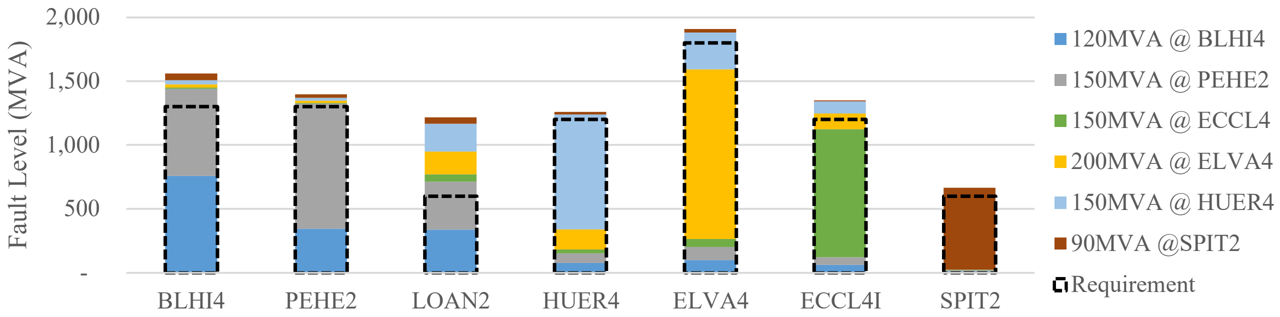

Figure 3: Modelled solutions to stability pathfinder and their fault level contribution at each area of requirement.

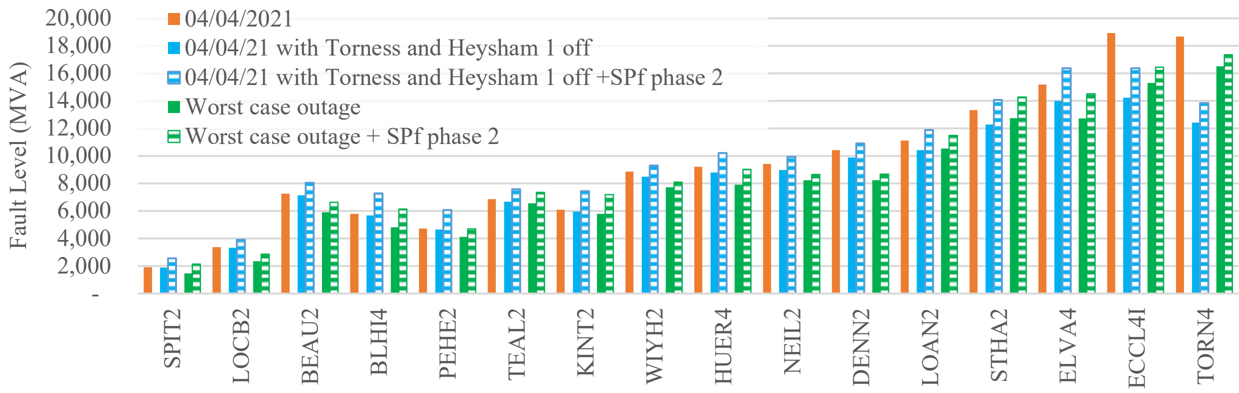

Figure 4: Fault level contribution from Stability Pathfinder Phase 2 (assumed solutions)

3.6 Discussion on minimum fault level requirements and challenges in Scotland

Defining a minimum threshold for fault level at any given location is challenging, in part because it depends on the exact way in which the low fault level manifests itself into operational issues. In GB, the general challenges of operating the system with a low fault level and low system strength have been identified in the 'system operability frameworks' published by NGESO [11], [30], [38]. These documents, along with the technical specification of the SPf tender requiring solutions to exhibit voltage source behaviour [35], imply that improved voltage sensitivity is needed in the system, as well as additional fault level. The occurrence of the SSO event in Scotland suggests that there are potentially significant challenges related to quasi-steady state voltage sensitivity, a potential cause of which can be IBR controller interactions (Section 2.3.1), and, as shown in Section 3.3, might not be prevented by maintaining minimum fault levels.

Defining a minimum fault level requirement may not always provide a solution to the problem at hand and could lead to commissioning of new synchronous assets such as SCs where the most cost-effective solution to the problem might have been better tuning of the controls of IBRs or of existing synchronous machines. Moreover, where SCs are installed to improve the fault level, "system strength" or system inertia, further stability challenges can arise, such as the introduction of new oscillatory modes between the slower SC controls and fast IBR controllers [1] as well as conventional angular instability. These issues were observed in the ERCOT grid following the installation of two SCs in the Panhandle area. Dynamic studies identified active power oscillations between the SCs and the SGs in the rest of ERCOT grid, and further inter-area and intra-area oscillation modes were found following some contingencies [39]. A system is most susceptible to classic inter-area oscillations and angular separation when one group of synchronous machines is connected to another group by a relatively high impedance path under heavy power transfer. Given the topology of the Scottish transmission grid, the closure of existing large SGs, the growth of IBR, and the potential installation of a number of new SCs, associated mitigation measures for potential new oscillatory modes should be assessed and costed at the time of any change to the system.

4 CONCLUSIONS

This paper has reviewed the use of fault level metrics in power systems with a high penetration of IBRs and discussed use of the term "system strength". It has been noted that a system is commonly described as having "low system strength" either when fault levels are low, or when there is high voltage sensitivity.

The paper has highlighted that, although fault level and system strength are related, a low fault level at a given location does not necessarily mean that the quasi-steady state voltage sensitivity is high. Furthermore, the established metrics for system strength are based on the fault level and an equivalent Thevenin impedance, meaning that they may not properly represent the system's behaviour in the context of high converter penetration. Hence, it is argued that there is a need to make a clearer distinction between low fault level issues and high voltage sensitivity. Making this distinction can be useful because, in general, there can be different solutions which satisfy one or the other. For example, some challenges such as converter control interactions could be resolved via solutions which do not provide additional fault level.

This paper has also reviewed fault levels in the Scottish transmission area of the GB power system, an area which has a high penetration of IBRs and few large SGs with some being close to retirement. It is shown that, in some locations and due to the locational effects of fault level contribution, the closure of the main synchronous generating plant in Scotland may not significantly reduce local fault levels much below those that are already being experienced. Equipment outages can reduce the fault levels more than a change to the status of the available large synchronous generating units. If fault levels are already judged to be too low, this can have significant implications for system outage planning. In addition, this paper has assessed the potential contribution from the Stability Pathfinder Phase 2 tender programme, which, motivated by closure of large SGs, seeks to procure additional fault level at specific locations in Scotland. However, it is difficult to discern the exact issues requiring the additional fault level as the fault level at other locations is already low and is not very sensitive to the anticipated closure of SGs in the area or the meeting the requirements of the tender exercise through installation of SCs. Further, a recent sub-synchronous oscillation event suggests that challenges related to a high quasi-steady state voltage sensitivity exist in Scotland. Analysis shown in this paper suggests little correlation of the oscillation event with low fault level. Hence, procurement of fault level alone may not be adequate to address some of the operational issues in the Scottish transmission system with further integration of IBRs.

More research should be done on defining system need (for example in defining voltage regulation and small signal stability requirements). In order that security of supply can be ensured in the most cost-effective manner, a single, simple 'system strength' metric is, we suggest, unlikely to suffice. Furthermore, analyses capable of assessing electromagnetic transients in the presence of IBRs are likely to be of increasing importance. However, they do also raise significant challenges, not least around the time and expertise required to run them and the need for considerable amounts of data. It is therefore important to have a clear understanding of the issues being addressed before embarking on detailed studies of any kind.

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